Modeling Wettability Alteration using Chemical EOR Processes in Naturally Fractured Reservoirs

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by
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ABSTRACT

The objective of our search is to develop a mechanistic simulation tool by adapting UTCHEM to model the wettability alteration in both conventional and naturally fractured reservoirs. This will be a unique simulator that can model surfactant floods in naturally fractured reservoir with coupling of wettability effects on relative permeabilities, capillary pressure, capillary desaturation curves, and dispersivities.

The capability of wettability alteration will help us and others to better understand and predict the oil recovery mechanisms as a function of wettability in naturally fractured reservoirs. The lack of a reliable simulator for wettability alteration means that either the concept that has already been proven to be effective in the laboratory scale may never be applied commercially to increase oil production or the process must be tested in the field by trial and error and at large expense in time and money.

The objective of Task 1 is to perform a literature survey to compile published data on relative permeability, capillary pressure, dispersion, interfacial tension, and capillary desaturation curve as a function of wettability to aid in the development of petrophysical property models as a function of wettability. The new models and correlations will be tested against published data. The models will then be implemented in the compositional chemical flooding reservoir simulator, UTCHEM. The objective of Task 2 is to understand the mechanisms and develop a correlation for the degree of wettability alteration based on published data. The objective of Task 3 is to validate the models and implementation against published data and to perform 3-D field-scale simulations to evaluate the impact of uncertainties in the fracture and matrix properties on surfactant alkaline and hot water floods.

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INTRODUCTION

We have developed UTCHEM simulator over many years with the support of the Department of Energy and it is clearly the most versatile reservoir simulator for chemical EOR processes. Here we are adapting UTCHEM to model the wettability alteration in both conventional and naturally fractured reservoirs. This will help us and others to better understand and predict the oil recovery mechanisms as a function of wettability in naturally fractured reservoirs. The predictive simulations of such complex processes will aid to reduce the risk of failure of the field projects.

The primary focus of this research proposal is on surfactant processes, which recovers additional oil through ultra-low interfacial tension and also through wettability alteration. The secondary objective is to model the wettability alteration during hot water injection, which enhances oil recovery by mobility reduction and also wettability alteration. The combination of surfactant and hot water injection will also be investigated to assess the potential for improved oil recovery of moderately heavy oils in naturally fractured rocks. The enhanced simulator to be developed as part of this research will make it possible to select and optimize the best candidates for field application and tailor process design to the particular characteristics of each reservoir.

The objective of this research is to develop a simulation tool to improve our understanding of multiphase flow of surfactant at elevated temperature in naturally fractured oil reservoirs. The emphasis is on enhanced oil recovery processes that reduce the interfacial tension, reduce the mobility ratio, and any possible enhancement due to wettability alteration. The project comprise of three tasks where Task 1 is the development of petrophysical properties as a function of wettability, Task 2 is the development of wettability correlation, and Task 3 is the field-scale simulations. We report on our progress on Tasks 1 and 2 for the first six months of the project.

EXECUTIVE SUMMARY

Increased domestic oil production using advanced technologies of enhanced oil recovery processes involve numerical modeling of such processes to minimize the risk involved in development decisions. The oil industry is requiring much more detailed analyses with a greater demand for reservoir simulations with geological, physical, and chemical models of much more detail than in the past.

Fractured, mixed-wet formations usually have poor waterflood performance because the injected water tends to flow in the fractures and spontaneous imbibition into the matrix is not very significant. Surfactants have been used to change the wettability with the goal of increasing the oil recovery by increased imbibition of the water into the matrix rock. Very little is known about the detailed mechanisms of this process and the interactions with the geochemical and geological properties of the oil reservoir, what conditions are most favorable for enhancing the rate of imbibition, and how this process compares with alternative oil production methods from such reservoirs.

Although laboratory experiments are essential, it is impossible to predict the performance of these complex processes with only laboratory experiments. Reservoir simulation is required to both scale up of the process from laboratory to field conditions and understand and interpret reservoir data. Without detailed, mechanistic simulations it is very unlikely that a cost-effective process can be developed and applied economically.

The objective of our search is to develop a mechanistic simulation tool by adapting UTCHEM to model the wettability alteration in both conventional and naturally fractured reservoirs. This will be a unique simulator that can model surfactant floods in naturally fractured reservoir with coupling of wettability effects on relative permeabilities, capillary pressure, capillary desaturation curves, and dispersivities.

The capability of wettability alteration will help us and others to better understand and predict the oil recovery mechanisms as a function of wettability in naturally fractured reservoirs. The lack of a reliable simulator for wettability alteration means that either the concept that has already been proven to be effective in the laboratory scale may never be applied commercially to increase oil production or the process must be tested in the field by trial and error and at large expense in time and money.

The objective of Task 1 is to perform a literature survey to compile published data on relative permeability, capillary pressure, dispersion, interfacial tension, and capillary desaturation curve as a function of wettability to aid in the development of petrophysical property models as a function of wettability. The new models and correlations will be tested against published data. The models will then be implemented in the compositional chemical flooding reservoir simulator, UTCHEM. The objective of Task 2 is to understand the mechanisms and develop a correlation for the degree of wettability alteration based on published data. The objective of Task 3 is to validate the models and implementation against published data and to perform 3-D field-scale simulations to evaluate the impact of uncertainties in the fracture and matrix properties on surfactant alkaline and hot water floods.

Here we report on our initial efforts on Tasks 1 and 2 for the first six months of the project. We have performed an extensive literature survey to compile the relative permeability and capillary pressure data for different wettability conditions. A simple option is implemented in UTCHEM for wettability alteration. Multiple tables of relative permeability and capillary pressure vs. water saturation are included in the input file to represent different wetting conditions.

EXPERIMENTAL

This project does not include an experimental component.

RESULTS AND DISCUSSION

The initial progress on Tasks 1 and 2 is reported as discussed below.

Task 1: Development of Petrophysical Properties as a Function of Wettability

Subtask 1.1: Literature survey and model development

We have performed an extensive literature search to gather the data for relative permeability and capillary desaturation curves for different wetting conditions. We have developed a procedure to compute the relative permeabilities as a function of wettability altered due to the surfactant injection incorporating the trend in the published data such as residual nonwetting saturation vs. Amott-Harvey Wettability Index.

The wettability is the measure of the preference that a rock has for a particular fluid. If a rock is water-wet, the water phase will occupy the small pores and coat the remaining rock surfaces. The location of the fluids in an oil-wet rock will reverse from the water-wet case. In some instances, a rock will not have a strong preference for any fluid and is thought to have a neutral wettability. In other cases, a rock will have a varying wettability throughout and is defined as having mixed wettability (Anderson, 1986). Presently, three methods (USBM, Amott-Harvey, and contact angle measurements) are used to calculate the wettability of a rock. For this work, data obtained from the Amott-Harvey method was used. The Amott-Harvey wettability test utilizes a series of spontaneous imbibition and forced displacement processes to calculate the change in fluid volumes expelled from the core as described in Amott, 1959. The Amott-Harvey wettability index (I_w) can range from 1 (strongly water-wet) to -1 (strongly oil-wet). The wettability of a rock is important because it controls the residual oil saturation, relative permeability curves, and the capillary desaturation curves (CDC).

The effect of wettability on the residual saturation is based on the location and distribution of the fluids within the rock pores. The wetting phase, occupying the small pores and coating the walls of the larger pores, is immobile due to high capillary forces. The non-wetting phase, which is present as globules in the large pores or across several pores, is held immobile by the interfacial tension between the two phases. Several papers have documented the change in residual oil saturation with changes in the Amott-Harvey Wettability Index (Figure 1). The common conclusion is that the residual oil saturation is lowest under neutral-wet conditions. Data provided by Jerauld, 1997 indicates that the residual water saturation also follows a similar tend. Another interesting finding is the trend of the residual oil saturation under oil-wet conditions, which mirrors the trend under water-wet conditions (Figure 1).

The water/oil relative permeability curves are also dependent upon the wettability state of a rock. The primary changes to the relative permeability curves are the location of the crossover point and the movement of the endpoint relative permeabilities for water and oil. For a strongly water-wet rock, the crossover point of the water/oil relative permeability curves will occur at a water saturation greater than 0.5. This effect is due to the low water endpoint relative permeability (~0.1 to 0.3) and high oil endpoint relative permeability (~1). For a strongly oil-wet rock, the crossover point will occur at water saturation of less than 0.5. This is due to the higher water endpoint relative permeability (~0.4 to 0.7) and reduced oil endpoint relative permeability. To a lesser extent, the relative permeability curves are shifted due to the changes in residual phase saturations of differing wettability conditions. An example of the change in relative permeability with changes in wettability was obtained from Morrow, 1973 and curve fitted using Corey type parameters as shown in Figure 2. It is apparent from this example that the primary effects of changes in wettability are the increase in the water relative permeability curve and the decrease in the oil relative permeability curve when shifting from water-wet to oil-wet. This effect is shifting the crossover point to lower water saturations. The minor effects of changes in residual oil saturation can also be seen.

The effect of wettability on capillary desaturation is also apparent. Local phase trapping occurs until the viscous forces overcome the capillary forces. A dimensionless constant to relate the viscous and capillary forces known as the capillary number was first introduced by Brownell and Katz, 1949. A common usage of the capillary number is to relate it to the residual phase saturations using a CDC. An example CDC for a water-wet sandstone is shown in Figure 3. As expected, the wetting phase (water) requires a higher critical capillary number (N_{cc}) to begin desaturation compared to the non-wetting phase (oil). The critical capillary number is the capillary number at which the residual oil saturation starts decreasing. Table 1 gives a summary of the literature survey on the CDC for different rock types with the reported wettability Index (I_w). The low capillary number values of residual oil and water are also reported (S_{or}^{low}, S_{wr}^{low}). The published data were fit to the correlation for residual oil vs. capillary number (Equation 1) to obtain the trapping parameters for both oil and water (T_o, T_w). The trapping parameters are listed in Table 1.

$$S_{jr} = \min\left(S_j, S_{jr}^{high} + \frac{S_{jr}^{low} - S_{jr}^{high}}{1 + T_j N_{cj}^{\tau_j}} \right) \qquad (1)$$

Where, $S_{jr}^{high} =$ Residual saturation of phase j at high capillary number

$S_{jr}^{low} =$ Residual saturation of phase j at low capillary number

$T_j =$ Trapping parameter for phase j

$N_{cj} =$ Capillary number for phase j

$\tau_j =$ Trapping parameter exponent for phase j

The effect of changes in wettability on the CDC of a Berea sandstone is shown in Figure 4. This plot shows the variation of the critical capillary number for the oil phase and the residual oil saturation at low capillary number for different wettability conditions. Changes in the CDC for weakly oil-wet and neutral-wet carbonate rocks are shown in Figure 5. The key observation of this plot is the extremely low values of N_{cc} for each curve. The N_{cc} for the carbonate rocks in Figure 5 is three orders of magnitude lower than the mixed-wet and oil-wet sandstone values shown in Figure 4. A few possible explanations can describe the behavior of a carbonate compared to a sandstone: differences in pore-size distribution, permeability, porosity, and fluid distributions.

Subtask 1.2: Implementation

Wettability is a very important parameter controlling the relative permeability and capillary pressure. However, the wettability is not an explicit parameter in the flow equations but its effects should be reflected by the changes in capillary pressure and relative permeability curves. A preliminary option for wettability alteration is added to UTCHEM to model the change in relative permeability and capillary pressure using multiple tabular data. Using table look up option UTCHEM can now read multiple tables for relative permeability and capillary pressure to represent different wetting conditions. At the initial conditions the reservoir may be taken as oil-wet or mixed-wet and input tables of saturation and relative permeability and capillary pressure for these conditions are used. The alteration of wettability with time is modeled by injecting surfactant solution. Once the surfactant concentration in each gridblock reaches a tolerance input value, corresponding to the laboratory value at which wettability changes, the relative permeabilities and capillary pressure for water-wet conditions are used.

The implementation in UTCHEM involved the modification of existing subroutines and addition of new routine. For instance, in the main program (AAMAIN), a new conditional cycle was included to allow the user to choose whether changes in capillary pressure and relative permeabilities after the surfactant injection should be taken into account or not. The user decides to use the new utility by including a new variable in the input data called ITAB. When the value of ITAB is equal to 1 then the changes in capillary pressure and relative permeabilities, due to variations in wettability, are simulated. A new subroutine called KRPC was created and called from the main program. This subroutine reads the data point of relative permeabilities and capillary pressures versus water saturation from the input tables and interpolates the data for other saturation values. Surfactant concentration in each gridblock is compared to an input tolerance value of WETI. The WETI parameter represents the value at which a change from either oil-wet or mixed-wet to more likely water-wet condition happens in each gridblock. When the surfactant concentration is greater than WETI, the tables of capillary pressure and relative permeabilities for a water-wet system are used. In the remaining cases with surfactant concentrations lower or equal to WETI, the tables representing the initial wetting state of oil-wet or mixed-wet are used. Modifications were also made in subroutine INOUT by calling two new subroutines: IUTIL and TABLE. The first routine is used just for initialization of some variables; the second one calls some other utility routines (LOOKUP, NUMBER, SPLINE, PRTTAB, PRTSPL, etc). These subroutines allow interpolating and extrapolating the relative permeability and capillary pressure data in each table. Multiple tables can be read for each property. The switching data of relative permeability and capillary pressure tables between two conditions, water-wet and mixed-wet are performed by giving two sets of table for each property representing different wetting state. The user provides the tabular data as the input data.

The subroutine RPERM0 is called from subroutine TIME0 in the main program and its purpose is to calculate relative permeabilities and capillary pressure at the start of the simulation (at time zero). A new section was included in subroutine RPERM0 to initialize these properties assuming mixed-wet or oil-wet conditions. The initialization is done by reading the tables corresponding to mixed-wet or oil-wet conditions through the table lookup subroutine. We have successfully implemented and tested the table look up option for wettability alteration.

Task 2.0 Development of Wettability Correlation

As a result of the extensive literature survey and test simulations, the effects of wettability on residual oil saturation, relative permeability curves, and CDCs are clear. However, a mathematical relationship to link the changes of each property with changes in wettability due to surfactant injection is unclear. A preliminary method has been established in an attempt to fulfill this complex task.

CONCLUSIONS

We have performed an extensive literature search to gather the data for relative permeability and capillary desaturation curves for different wetting conditions. We have developed a procedure to compute the relative permeabilities as a function of wettability altered due to the surfactant injection incorporating the trend in the published data such as residual nonwetting saturation vs. Amott-Harvey Wettability Index.

We have adapted UTCHEM to model the changes in rock wettability due to the surfactant injection. A preliminary approach implemented in UTCHEM is to define two sets of relative permeability and capillary desaturation curves for each phase, one set is taken to model the altered wettability condition and the other for initial oil-wet condition. Once the surfactant solution is injected and its concentration is above an input tolerance concentration, the wettability alters to water wet and the corresponding tables of relative permeability and capillary pressure are used.

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Table 1. Summary of Literature Search to Obtain Trapping Parameter Data

Source	Rock Type	I_w	S_{or}^{low}	S_{wr}^{low}	T_o	T_w
Bhuyan, 1986	Berea Sandstone	0.57	0.33	0.39	17791	781
Bhuyan, 1986	Berea Sandstone	-0.65	0.35	0.38	53452	3206
Bhuyan, 1986	Berea Sandstone	-0.7	0.26	0.34	35000	55999
Kamath, 2001	Oolitic Limestone	-0.25	0.6	NA	1000000	NA
Kamath, 2001	Limestone	-0.19	0.5	NA	200000	NA
Kamath, 2001	Micritic Limestone	-0.04	0.32	NA	400000	NA
Abrams, 1975	Gallup Sandstone	NA	0.34	NA	1500	NA
Abrams, 1975	Dalton Sandstone	NA	0.3	NA	1000	NA
Abrams, 1975	Dalton Sandstone	NA	0.29	NA	2000	NA
Abrams, 1975	Paluxy Sandstone	NA	0.28	NA	2500	NA
Abrams, 1975	Bandera Sandstone	NA	0.37	NA	1500	NA
Abrams, 1975	Berea Sandstone	NA	0.37	NA	3000	NA
Abrams, 1975	Indiana Limestone	NA	0.34	NA	500	NA
Gupta, 1979	Berea Sandstone	0.95[1]	0.25	0.42	8000	2500
Chatzis, 1981	Berea Sandstone	0.92[1]	0.34	NA	2000	NA
Chatzis, 1981	Berea Sandstone	0.92[1]	0.35	NA	4000	NA
Chatzis, 1981	Berea Sandstone	0.92[1]	0.34	NA	1000	NA
Chatzis, 1981	Berea Sandstone	0.92[1]	0.39	NA	1300	NA
Chatzis, 1981	Berea Sandstone	0.92[1]	0.3	NA	2400	NA
Chatzis, 1981	Cottage Grove Sandstone	NA	0.37	NA	2000	NA
Chatzis, 1981	Boise Sandstone	1[1]	0.27	NA	3000	NA
Chatzis, 1981	Fountainbleau Sandstone	NA	0.34	NA	3200	NA
Stegemeier, 1974	Berea Sandstone	0.84[1]	0.4	NA	3000	NA
Amaefule, 1982	Berea Sandstone	0.91[1]	0.2	0.4	1500	200
Mohanty, 1983	Berea Sandstone	0.79[1]	0.36	NA	4000	NA
Mohanty, 1983	Berea Sandstone	-0.75[1]	0.48	NA	1000	NA
Mohanty, 1983	Berea Sandstone	0.07[1]	0.26	NA	1000	NA
Bardon, 1980	Fountainbleau Sandstone	NA	0.4	NA	3000	NA
Boom, 1995	Reservoir Sandstone	NA	0.09	0.29	500	79
Boom, 1996	Reservoir Sandstone	NA	0.26	NA	315	NA
Delshad, 1990	Berea Sandstone	NA	0.4	NA	35000	NA
Henderson, 1998	Berea Sandstone	NA	0.29	NA	100000	NA
Henderson, 1998	Berea Sandstone	NA	0.27	NA	14854	NA
Garnes, 1990	Berea Sandstone	0.77[1]	0.49	NA	5000	NA
Garnes, 1990	Berea Sandstone	0.77[1]	0.6	NA	9000	NA
Garnes, 1990	Berea Sandstone	0.77[1]	0.45	NA	6000	NA
Garnes, 1990	Tarbet Sandstone	0.3	0.27	NA	1600	NA
Garnes, 1990	Oregon Sandstone	NA	0.45	NA	15000	NA
Garnes, 1990	Oregon Sandstone	NA	0.32	NA	8000	NA

NA - Not Available

1: I_w was obtained from a different source based on the core treatment process, initial water saturation, and brine.

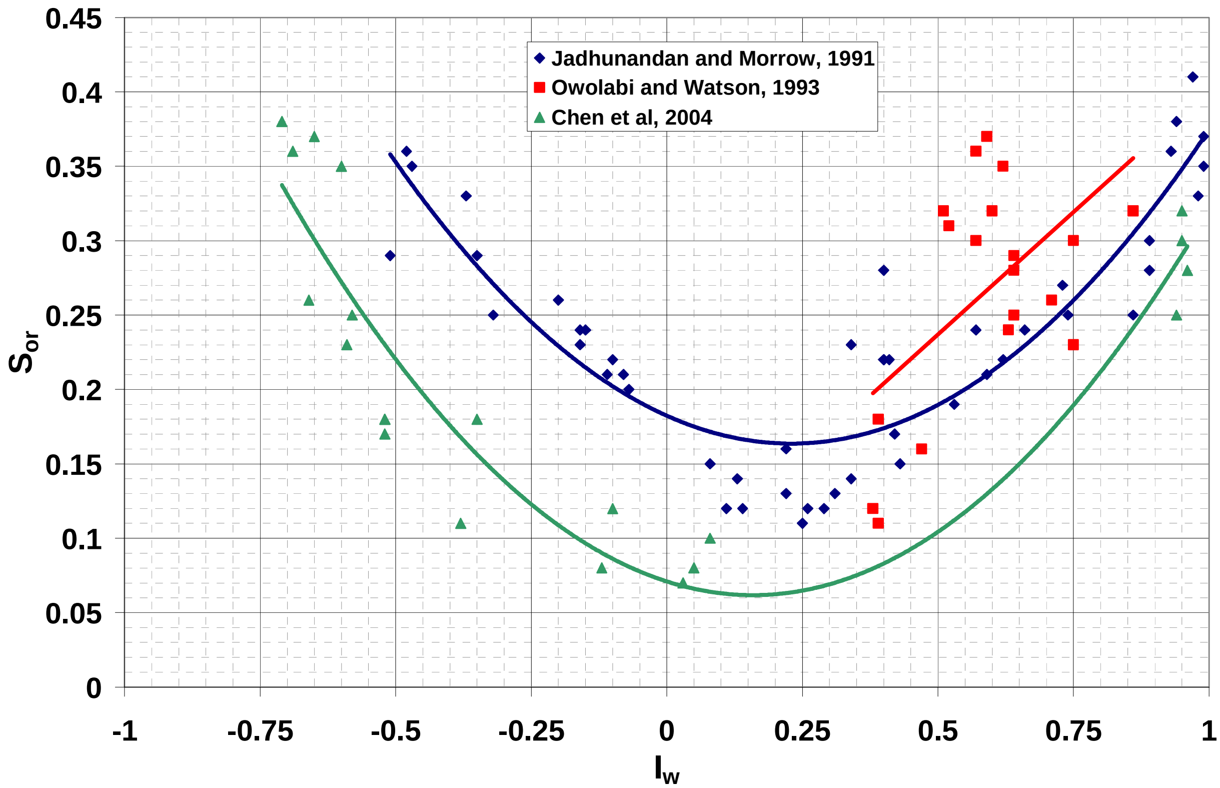

Figure 1. Effect of Amott-Harvey Wettability Index on Residual Oil Saturation in Berea Sandstone

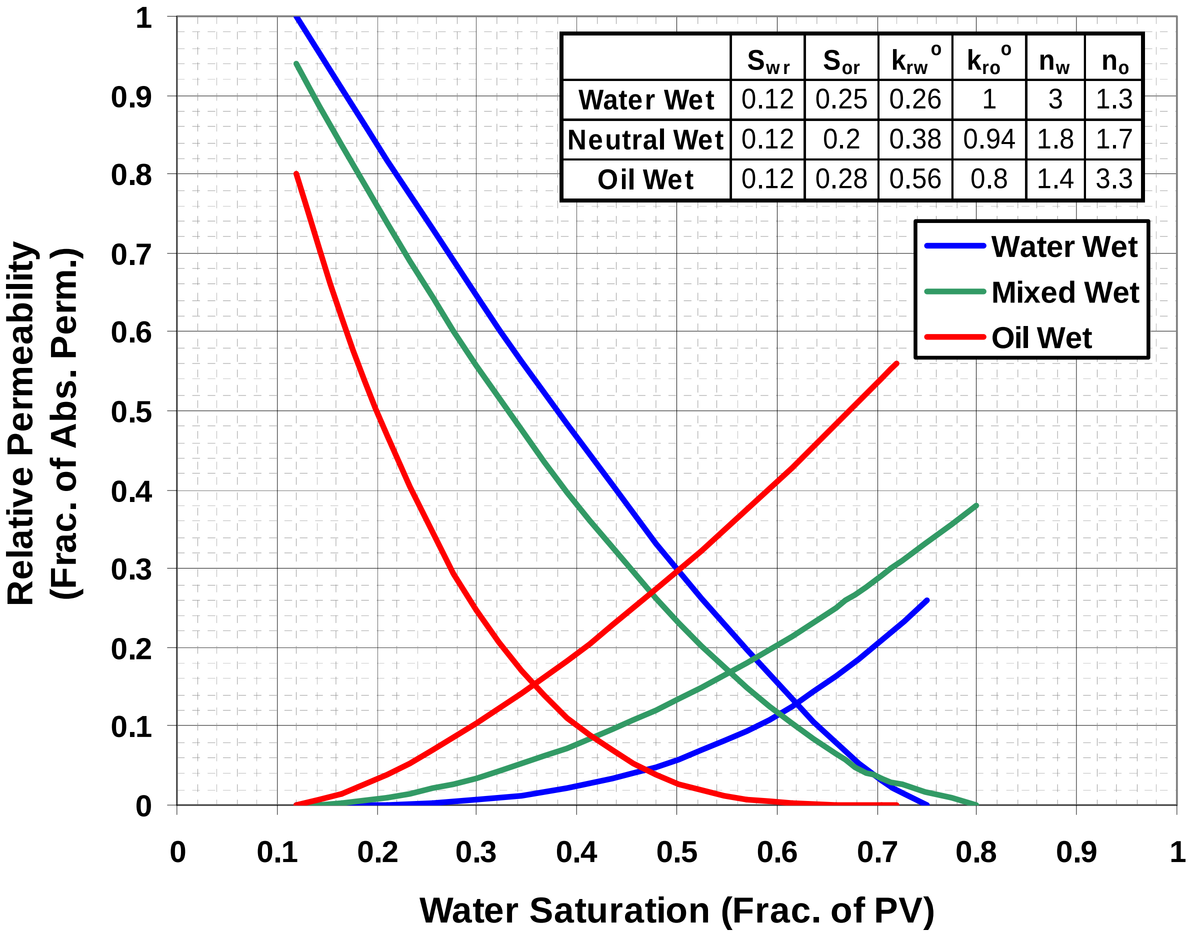

Figure 2. Effect of Wettability on Oil/Water Relative Permeability Curves (Morrow *et al.* 1973)

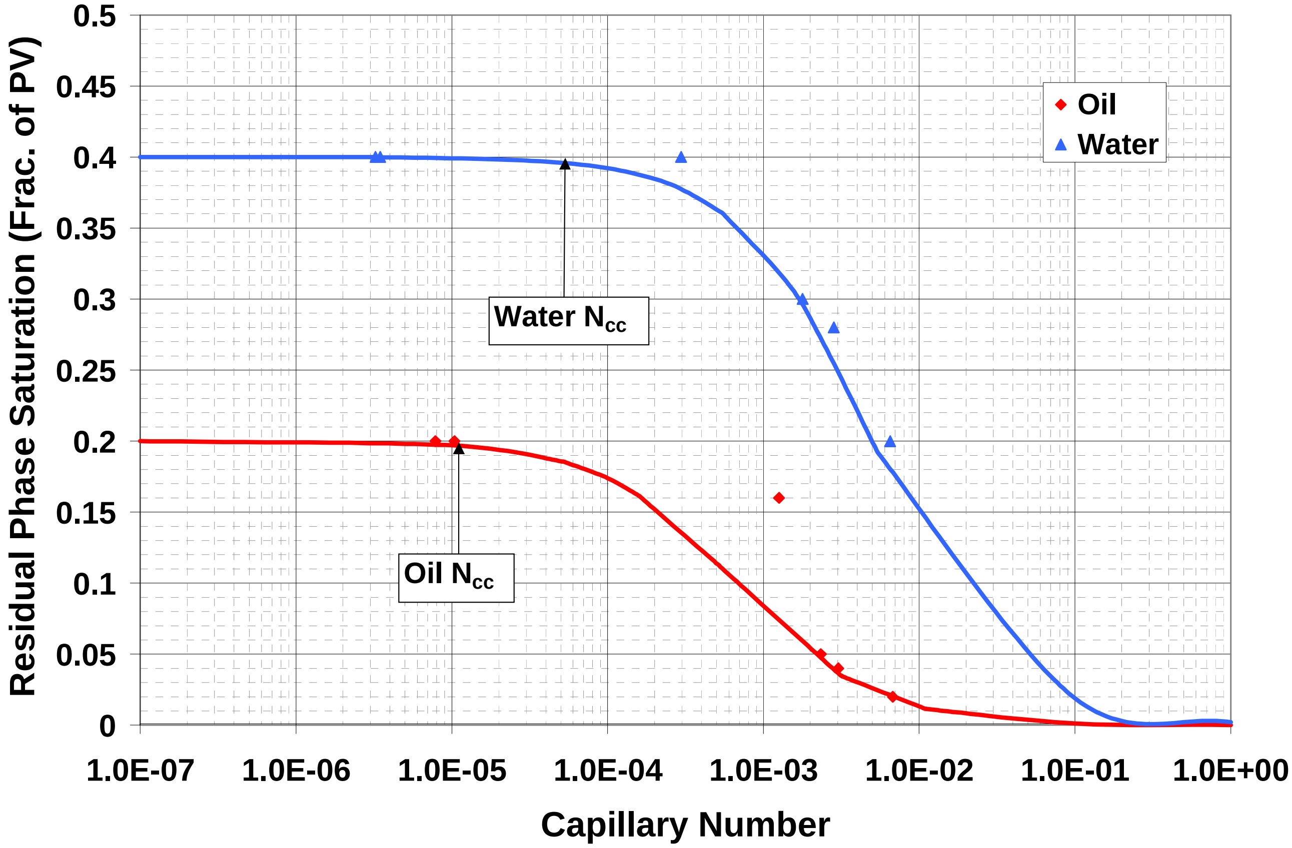

Figure 3. Example Water/Oil CDC for a Water Wet Berea Sandstone (Amaefule, 1982)

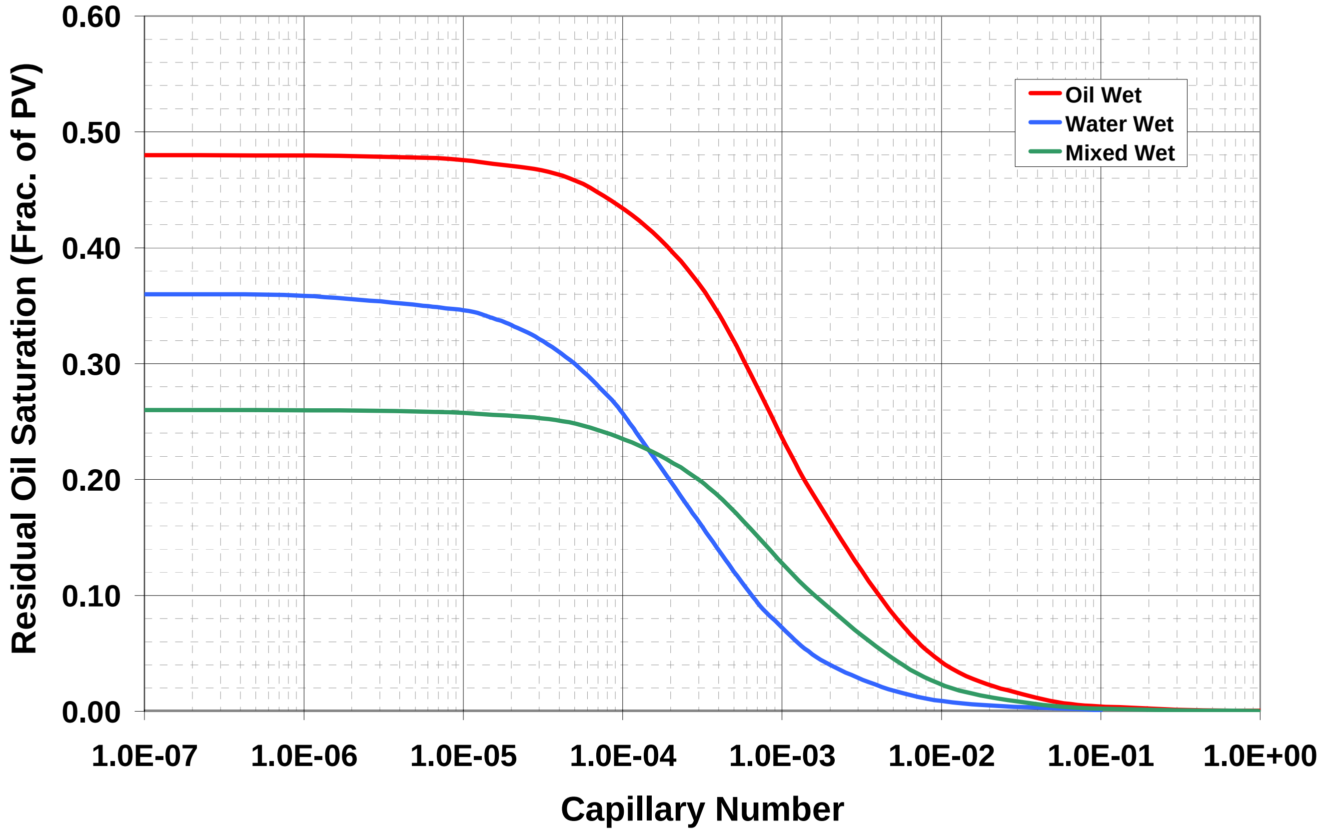

Figure 4. Effect of Wettability on the CDC for a Berea Sandstone Core (Mohanty, 1983)

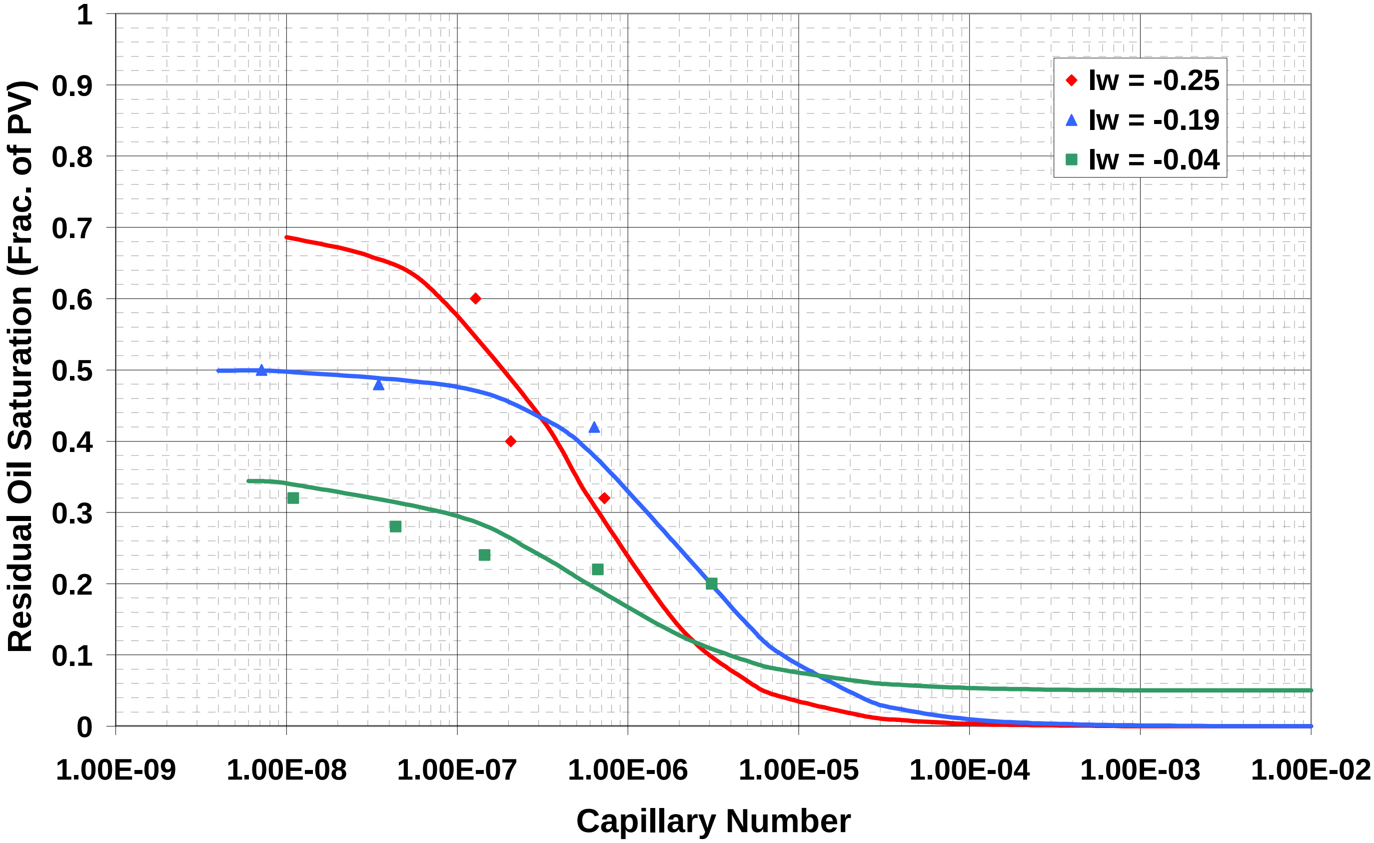

Figure 5. Effect of Wettability on the CDC for Three Weakly Oil-Wet to Neutral-Wet Carbonate Rocks (Kamath, 2001).